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Co-firing of biomass waste-derived syngas in coal power boiler

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ABSTRACT

The paper deals with waste gasification as a technology allowing for indirect co-firing of large quantities of biodegradable wastes in coal-fired power boilers. In contrast to common landfilling and direct co-firing, gasification of wastes presents a number of advantages. Problematic species in original feedstocks can be partly safely incinerated in the furnace and partly retained in the gasification residues.

The paper focuses on the impact of indirect co-firing on basic boiler parameters and performance. The work carried out was in the form of a case study for co-firing LCV gas in a 230 t/h dual fuel pulverized coal-gas fired boiler. Thermal shares of 10, 20 and 40% have been investigated for two extreme LCV gas qualities represented in the calculations by its calorific value of 2.0 and 8.5 MJ/m_n^3 respectively, thus six calculation cases are given. The results of the study reveal that even high thermal shares of LCV gas may be achieved for co-firing of better quality gas without significant effects on boiler operation. For lower quality gas, even a 10% thermal share influenced boiler operation to a great extent. This paper also gives consideration in relation to avoided CO_2 emissions accomplished via indirect co-firing.

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1. Introduction

Thermal disposal of wastes is a source of constant public discussion and consequently has become the subject of strict legislation [1]. Most municipal solid waste (MSW) has energy locked up in it in the form of chemical energy that can be recovered by combustion. Nowadays, waste to energy combustion plants are widely used to recover energy from MSW and successfully reduce both volume and health hazards. However, energy recovery may technically be realized in different ways. One of the options, especially targeting environmentally sound waste disposal, is pyrolysis and/or gasification of wastes. The resulting low calorific value syngas (LCV gas) produced may then be utilized in various applications including subsequent firing in steam boilers. While this technology is quite widely used in the waste treatment industry [2], it has not yet been fully applied for co-incineration of wastes in power plants due mainly to the fact that in the EU, emission from any plant thermally treating waste, even by gasification or pyrolysis, is covered by the waste incineration Directive 2000/76/EC [3]. The greatest potential is co-firing of gasifier syngas in large pulverized coal (PC) boilers which normally operate at high steam parameters and therefore have much higher thermal efficiencies compared with waste to energy plants.

To comply with the Directive on the incineration of waste [3], the plant has to fulfil a number of requirements. The big concerns resulting from the implementation of the Directive are certain operating conditions defined in the document, namely those stating that for proper co-incineration, the gases evolved shall be raised to a temperature of 850 °C for 2 s. Such conditions may be found in large combustion chambers of power boilers which are suitable for ensuring decomposition of dioxins. Yet, this requirement is conditional and it is upon national or local authorities how it is to be implemented. The absolute targets to be achieved, despite technical measures used and local furnace conditions, are stack emissions. This implies that in fact various combustion configurations may be implemented, even those not achieving the given temperature and residence time, so long as final emission limits are not exceeded.

Abbreviations: ACFBG, Atmospheric circulating fluidized bed gasification; ASR, Automotive shredder residues; BFG, Blast furnace gas; COG, Coke oven gas; ECO, Economizer; ESP, Electrostatic precipitator; FBG, Fluidized bed gasification; GB, Gas burner; HTAC, High Temperature Air Combustion; HTAG, High Temperature Air/steam Gasification; ICFB, Internal circulation fluidized bed; ID, Induced draught; IGCC, Integrated Gasification Combined Cycle; LCV, Low calorific value; MBM, Meat and bone meal; MSFB, Multistage fluidized bed; MSW, Municipal solid wastes; MW, Coal mill; OFA, Over fire air; PAH, Polyaromatic hydrocarbons; PC, Pulverized coal; PE, Polyethylene; PET, Polyethylene terephthalate; RAH, Rotary air heater; REF, Recycled fuel; S/F, Steam to feedstock ratio; SH, Superheater; SS, Sewage sludge

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The indirect co-firing seems to be particularly important for wastes regarded as difficult, i.e. those potentially releasing high amounts of tars, polycyclic aromatic hydrocarbons (PAHs) or furanes and dioxins [4]. The latter may be formed by thermal processing of chlorine containing wastes such as polyvinylchloride (PVC) which is present in plastic containing wastes, for example in Automotive Shredder Residues (ASR) or Municipal Solid Wastes (MSW). Other potentially hazardous waste to be treated in this way is meat and bone meal (MBM), whose safe disposal has become of particular interest since the introduction of new health legislation following the outbreaks of the cattle disease, BSE.

2. Direct vs. indirect co-firing of wastes

The percentages of biomass wastes directly co-fired in power boilers vary greatly from boiler to boiler. Fluidized bed boilers are less prone to suffer from negative effects of co-firing, nevertheless for the present study the pulverized coal fired boiler is chosen for which typically these percentages do not exceed 5% on an energy basis.

There are several challenges when direct co-firing of biomass wastes in pulverized boilers [5]. Milling properties of biomass wastes containing fibres are more difficult than those of brittle fossil fuels. It is possible to avoid milling problems by pre-treating biomass by torrefaction prior to feeding into coal mills or by building dedicated milling installation for biomass only. Torrefaction is also beneficial in removing volatile alkali metals (K, Na) that lower ash fusion temperatures and enhance ash deposition onto boiler heat exchangers [6]. The influence of direct co-firing of various biomass fuels on boiler operation has been carefully studied previously [7]. Several drawbacks, including a pronounced tendency for fouling and slagging and consequent problems with superheaters (steam attemperators) and drop in boiler efficiency were contrasted to a few beneficial effects, namely decrease of ash stream to be removed from the boiler when wood and straw are co-fired and increase of air preheat which consequently helps to mill high moisture content biomass.

Generally, direct co-firing will bring about the following problems and challenges:

- biomass wastes pre-treatment and feeding,
- fouling, corrosion, modified boiler operation and flue gas treatment,
- residues utilisation,
- modification of heat transfer in the boiler.

By indirect co-firing of biomass wastes a number of problems related to deterioration of ash quality may be avoided. Nevertheless, injection of typical LCV gas obtained from gasification of biomass will also have some negative effects, although less pronounced than in the case of direct co-firing. These negative effects will occur in the gasification installation, and can be better managed there than in the boiler itself. The main difficulties may be expected in the LCV gas cooling unit, if the product gas has to be cooled for purification [8].

The clear advantage of gasification over direct waste co-firing is connected with retention of some substances which normally affect high temperature corrosion of furnace components. Also, severe fouling problems of the heat exchanger systems caused by inorganic components can be avoided [9].

Indirect co-firing of wastes can cause the following operating problems:

- bed agglomeration (in the case of Fluidized Bed Gasification (FBG)),
- tar condensation and intensive fouling in cool sections of the plant,
- problems with utilisation of gasification residues,
- modification of heat transfer in the boiler.

Fig. 1 depicts expected problems related to co-firing in direct or indirect systems. It should be noted that for indirect co-firing the main technical problems, apart from heat transfer issues, are not associated with the power boiler.

3. Prospective solutions for LCV co-firing

Injection of LCV gas by means of dedicated nozzles could resemble the configuration commonly used for High Temperature Air Combustion HTAC (also known under acronyms Mild Combustion, HPAC, HiCOT). HTAC's operation principle is to use separate high velocity flows of preheated reactants to create large recirculation/mixing zones. The technology is already proven for gas-fired furnaces in the steel making industry in terms of significantly reduced emissions and homogeneous temperature distribution, nevertheless is still not applied for power generation [10].

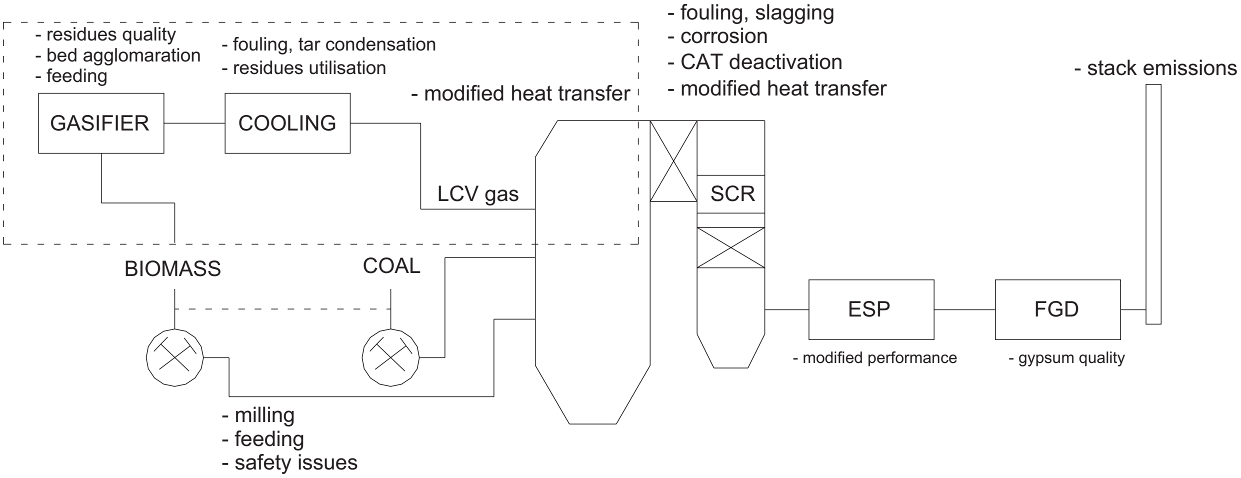

Fig. 1. Areas of concern related to direct or indirect (dashed line domain) co-firing [8].

Despite research efforts in Europe [11] and Japan [12] even less data is available on high temperature combustion of coal, nevertheless it is likely that LCV syngas, upon combustion with slight excess air, could serve as a surplus source of preheated oxidizer providing better conditions for coal HTAC. Simultaneously the use of regenerators for air preheating could be avoided, thus eliminating problems of fouling by fine ash particles.

4. Selection of gasification technology for indirect co-firing

For the particular application of a gasifier as a source of gas derived from biomass waste streams and subsequent co-firing, in fact no extra gasification features are required. Robust, atmospheric air gasifiers operating at temperatures around 800 °C could be a feasible option if their relatively low efficiency is of minor importance and environmental requirements are still met. Fluidized bed or fixed bed gasifiers could be considered as a natural choice in such a case. However, as our study shows, for accomplishing large thermal shares of LCV gas, gas quality is an important parameter.

The actual choice of technology is more complicated when particularly difficult feedstocks are used and when it is required to vitrify the solid residues. More advanced technologies based on oxygen and/or steam or high oxidizer preheat temperature could then be considered, giving the advantage of:

- better gas yield
- non-leachable slag
- less tar and dioxins in the product gas.

Below, a short review of available techniques is provided together with operating recommendations and restrictions.

4.1. *Fluidized Bed Gasification (FBG)*

In a published paper [13], successful long-term runs of $50MW_{th}$ air fed atmospheric circulating fluidized bed gasifier (ACFBG) coupled with 450 t/h power boiler are reported. A variety of feedstocks had been investigated including biomass residues, recycled fuel (biomass and plastics) and shredded tyres. The resulting gas without any treatment was co-fired with regular pulverized coal and the maximum gasifier share of boiler thermal input was 16%. A low calorific gas, as low as 1.6–2.4 MJ/m_n^3 for high moisture feedstocks, was fed to two special burners with enlarged diameters. A unique feature of this configuration is the location of gas burners at the bottom of the furnace, below the coal burners. For the test runs comprehensive measurements of product gas quality as well as detailed boiler emission monitoring was performed. For particular test runs, deposit formation and corrosion monitoring was also carried out. As reported by Raskin et al. [13], no significant effect on the main boiler emissions was found while co-firing the product gas. This statement also stands for heavy metals, particulates, dioxins and PAHs when gasifying more difficult recycled fuels. Surprisingly, some decrease in NOx and SOx emissions was noted, the former attributed to the presence of ammonia and cooling effects of the product gas and the latter caused by the low sulphur content in the feedstocks.

In fact, high ammonia contents, generally treated as 'fuel-NO', and attributed to fluidized bed gasification product gas may lead to either increased or decreased NOx emission depending on the combustion process arrangement and reaction path. Possible decomposition of ammonia present in the product gas leading to desired N_2 formation is described in [14,15]. Small additions of oxygen or nitric oxide are postulated prior to combustion at temperatures of 800–1200 °C in order to convert NH_3 effectively. Moreover, a strong temperature effect connected with the large volume of relatively cool and wet product gas fed to the boiler additionally supports NOx reduction efficiency of the overall process [16].

A detailed CFD study on formation and reduction of NOx in an ACFBG installation described in Ref. [13] was given by Boström et al. [17]. They found that when co-firing biomass/waste derived gasification gas and coal, the main sources of NOx are thermal NO and fuel NO from coal while NOx originating from LCV gas is of minor importance. The thermal NOx is mainly formed on the highest (third) level of coal-burners in the boiler which were of conventional burner type in contrast to low-NOx burners on the first and second row. The ammonia in the gasification gas does not contribute to any additional NOx neither does it reduce NOx formed from the coal burners. The gas burners do, however, contribute to less thermal NOx from the coal burners due to the high moisture content in the gasification gas, and consequently, lower temperatures in the lower parts of the boiler.

The advantages associated with FBG technology are clear and comprise feedstock flexibility in terms of shape and composition and a large range of operating capacities. The disadvantages of FBG technology are mainly associated with relatively low energy content in the product gas and not vitrified gasification residues. Both constraints result from inherent FBG technology features. Fluidized beds are normally fed with air or mixtures of air and steam, with the resulting gas therefore containing unwanted nitrogen. Optimisation of steam share in air/steam mixture is thus recommended for better product gas quality. Oxygen-enhanced or FBG fed with a mixture of oxygen and recirculated flue gas are options not yet fully investigated, nevertheless they seem sensible to consider in view of improved CO_2 capture possibilities. Moderate operating temperatures in the range 800–850 °C generally avoid material bed agglomeration, but also generate bottom ash which may be leachable. For high alkali feedstocks (straw), even lower operating temperatures and some addition of steam are recommended for avoiding bed agglomeration [18]. Process temperatures and particularly bed temperatures are quite critical with respect to waste processing in FBG. For instance gasification of brown coal and PET (77/23 wt.%) blends have been considerably affected by fluidized bed temperature, while for pure coal gasification this effect is not pronounced and freeboard temperature is equally important [19].

In general, FBG technology is considered as mature in terms of process reliability. Demonstration or bench scale plants exist, some also coupled with boilers which have proven their high reliability and availability [8,13,18].

4.2. *Moving (fixed) bed gasification (MBG)*

Fixed bed gasifiers commonly designed as updraft or downdraft reactors are the most robust and mature gasifiers. They accept only solid feedstocks, nevertheless almost any solid material may be gasified. Depending on temperature in the combustion zone they may be subdivided into slagging or dry bottom gasifiers. Simpler design and operation are characteristic of updraft gasifiers, however they produce large amounts of tars which are generated during the pyrolysis step of the process and swept out of the gasification zone without undergoing any secondary reactions. In fact, these secondary reactions will eventually take place in the furnace of the boiler co-firing the product gas, which may or may not lead to operating problems depending on the completeness of combustion.

A critical component of MBG is its grate which, together with feedstock properties, should permit good bed permeability to avoid pressure drops and non-uniform channel burning [20].

MBG technology is mature with a number of applications reported [21], however, thermal outputs are rather limited. Fixed bed gasifiers for biomass are not likely to exceed capacities in the range 10–20 MW_{th}.

4.3. Entrained flow gasification (EFG)

The EFG technology is highly versatile with respect to feedstock. EFG can work with solid and liquid feedstocks, however an intensive pre-treatment would be necessary when waste and biomass feedstocks are to be gasified. In general, EFG requires prior pulverization of the feedstocks which then may be fed to the gasifier dry, or wet in the form of slurry. In practice, such operating principles require torrefaction of biomass and subsequent pulverization prior to feeding to the gasifier. In the case of feedstocks containing plastics, proper grinding may however be problematic. Nevertheless, as pointed out by Radtke et al. [22], almost all solid feedstocks which can be pulverized to approximately 70% <0.1 mm are acceptable. It is also reported that high temperature related to the EFG technology favours environmentally friendly utilisation of sewage sludge, chicken litter and MBM if only these feedstocks are co-gasified together with coal.

At present, EFG technology is well established for coal gasification plants [20] and it is a preferred technology for IGCC systems. EFG gasifiers are mainly oxygen blown and operate at high temperatures of 1200–1600 °C, thus generating vitrified slags. Typically the operating pressures are 2–8 MPa. Also, high flexibility of EFG is reported [23] – less than 1 h is necessary to bring a EFG gasifier from the cold state to full load, which is a significant advantage when in combination with gas turbine applications. High pressures and temperatures complicate reactor design and investment costs are higher. For the particular case of EFG coupled directly with a power boiler, the gasifier could be simplified by using an atmospheric pressure vessel.

4.4. Novel gasification techniques

Research efforts on gasification have led to the development of novel techniques giving better yields and desired product gas composition. While coupling existing boilers with novel pre-gasification steps is not always feasible or desirable, these techniques could be considered for new concepts of power boilers, the most promising being direct integration of the gasification step into a boiler furnace.

Recently, a study by Miccio et al. [24] regarding various concepts of FBG, namely Multiple Stage Fluidized Bed (MSFB) and Internal Circulating Fluidized Bed (ICFB), has been conducted. The aim was to explore the conditions that can maximize hydrogen production for fuel cell application, and where it was revealed that multi-stage gasification generally gives higher heating values of product gas in comparison to single-stage processes.

Conventional gasification (cold gasification) produces gas with relatively low calorific value which contains significant amounts of tar. If additional heat is provided to the gasification process via a highly preheated feed gas, a higher quality of the produced gas can be obtained. This is because decomposition of the solid fuel is enhanced, thereby both yield and energy content of the produced gas are increased. Moreover, a high gasification temperature favours cracking of tar and therefore results in a cleaner product gas. Much attention has been paid lately to processes benefiting from a highly preheated gasifying medium. The technology is often called HTAG which stands for High Temperature Air/steam Gasification and may be applied in fixed-bed [25] or entrained flow gasifiers [26].

In a study by Ponzio et al. [25], experiments with air/steam gasification of feedstock consisting of biomass and plastics have been described. An enhanced gas yield and calorific value have been reported. All factors describing tar behaviour indicated the positive influence of feed gas preheating – in this case above 1400 °C. In a study [26] by Ryu et al., good performance of an entrained flow reactor under ultra-superheated steam conditions has been reported. Wood char has been exposed to products of propane and synthetic air combustion resulting in a high temperature mixture of H_2O and CO_2. Good carbon conversion and product gas quality have been reported as an outcome.

5. Critical combustion parameters of LCV product gas

Combustion of low calorific gases, if performed without any precautionary measures, is a difficult task. The critical factor is lack of flame stability which is additionally pronounced for higher excess air ratios usually needed to achieve complete combustion of LCV gas. The lack of stability is a result of low flame propagation velocity of particular gas components.

As generally agreed, the two parameters describing combustion behaviour of LCV gas are:

- laminar flame propagation velocity
- adiabatic flame temperature.

Both these parameters are dependent on gas composition, temperature of reactants and operating parameters like amount of excess air.

The limiting velocity may be associated with combustion of CO. Therefore it is of obvious advantage to have hydrogen and/or hydrocarbons present in LCV gas, thus mitigating effects associated with CO combustion. A similar enhancing effect may be attributed to preheating of reactants [27].

Below, Table 1 lists compositions of product gases and main parameters which could be associated with different gasification technologies. Data on product gases resulting from gasification of biomass fuels and also mixtures of biomass and plastics are given. For a reference, also data concerning blast furnace gas (BFG), having similar features to some of the poor product gases, are given as this waste gaseous fuel is already reported to be used in power boilers [28]. In addition, coke oven gas (COG), an example of good quality gas, fired in different process industries is also shown.

First of all, the choice of oxidant has a strong influence on the composition of the syngas. Addition of steam promotes hydrogen yield regardless of the feedstock gasified; there exists a certain optimal steam-to-feedstock (S/F) ratio for each technology. In general, values of S/F >0.6 are recommended for biodegradable wastes, however certain technologies require lower oxidant flows per unit of feedstock and correspondingly much lower S/F factors, e.g. HTAG technology. Concerning steam additions, it must be clearly stated that LCV values as reported in Table 1 do not necessarily reflect operating reality. H_2O contents as high as 30–40% may easily be reached in a number of applications, thus lowering syngas LCV significantly and influencing its further applicability.

Air or air/steam fed gasifiers are currently the best developed and tested options for coupling with existing power boilers. Future applications targeted at CO_2 capture would have to run on oxygen.

Secondly, for thermodynamic reasons, gasification is best carried out at the highest possible temperature. This observation

Table 1
Properties of LCV product gases in relation to BFG and COG

Technology	BFG [28]	ACFBG [13]	FBG [29]	FBG [30]	MSFB[a] [24]	ICFB[a] [24]	HTAG [25]	COG [28]
Feedstock	–	Wood, REF, plastics	60% SS, 40% coal [wt.%]	60% PE, 40% pine [wt.%]	Wood	Wood	50% biomass, 50% plastics	–
Oxidizer	–	Air	Steam	Steam	Air/steam	Steam	Air/steam	–
S/F	–	–	1.0	0.8	0.3	0.3	1.0	–
T_{out} [°C]	–	850[b]	850[b]	835[b]	614	787	750	–
LCV[c] $[kJ/m_n^3]$	3626	6468	15697	18745	4904	9030	11060	16255
Dry composition [vol.%]								
H_2	1.5	8.8	30	50	33.4	60.7	17.1	56
CO	27	6.9	20	27	8.8	19.5	11.9	7
CO_2	15	19.2	30	3	21.8	19.5	9.8	2.5
CH_4	0	0	15	15	0.5	0	5.5	26
N_2	56	60	0	0	35.5	0.3	49.4	8
O_2	0.5	0	0	0	0	0	0	0.5
C_xH_y (as C_3H_8)	0	5.1	5	5	0	0	6.3	0
T_{ad} [°C]	1413	1544	1891	2020	1580	1946	1800	1989

[a] Modelling results.
[b] Reactor temperature.
[c] For dry composition.

is valid not only for fixed-bed or entrained flow reactors but also for fluidized bed reactors as long as bed agglomeration is avoided. Better gas yields and shift from heavy hydrocarbons into light gaseous compounds is commonly observed. Namely less tar is produced and there is a better chance that it will undergo thermal cracking within the process. The high temperature of product gases may be utilised in different ways, predominantly for oxidizer preheating, but also directly in the boiler furnace, preferably in the configuration similar to High Temperature Air Combustion (HTAC) [31] solutions.

6. Impact on PC boiler operation-a case study

Firing of additional fuel in power boiler changes the chemical composition and amount of the flue gas resulting from such co-firing. Flue gas properties are then changed in terms of radiation properties (emissivity, absorptivity) as well as in velocity and viscosity, thus influencing the convective heat transfer coefficient. The change of concentration and properties of solid particles can also influence the emissivity of fly ash present in the flue gas and may cause variation in fouling propensity. In consequence, during co-firing of biomass derived syngas the temperature of flue gas along boiler ducts and the temperatures of heated air can vary, changing the streams of tempering water in desuperheaters or lowering superheat temperatures below nominal values.

In fact, a high volume of low emissivity flue gas resulting from combustion of LCV gas could shift the heat transfer from the radiation zone further along the flue gas path that is designed to operate under convective heat transfer conditions. This is the most pronounced modification of heat transfer behaviour resulting in enhanced heat transfer over convection superheaters and the need for reconstruction of desuperheaters. With respects to this behaviour it is better to feed the lower burners with LCV syngas, lowering the furnace outlet temperature.

As an example of expected impacts for PC boilers co-firing LCV gas the calculation shown below was performed.

The boiler chosen for the present study is a dual-fuel, pulverized coal and gas fired boiler OPG 230 – see Fig. 2.

The boiler is a modification of the PC fired boiler OP 230 [32] manufactured by RAFAKO SA towards co-firing gaseous fuel. Five boilers of this type are being operated in one of the steel making plants in Poland. It is a steam boiler with natural circulation, whose basic parameters are given in Table 3. The boiler is equipped with a low-emission firing system consisting of staged air and pulverized coal. Staging is realized by having different concentrations of respective fuel-air streams for different burners. The firing system consists of 9 front wall PC burners and is presented in Fig. 3. The concentrated PC-air mixture coming from the three beater wheel mills MWk-16 is fed to the first and second burner rows while a diluted mixture is directed to the third, upper burner row. High up in the boiler, at the level 18.5 m, Over Fire Air (OFA) ports are located which are designed to swirl combustion gases in the furnace. On side walls of the furnace, at the level of the lowest PC burners, four gas fired burners are mounted. The boiler is lit by gas start-up nozzles built in the main coal burners.

Thermal calculations of the boiler were carried out according to procedures [33–35]. In general, calculations are based on estimation of furnace exit temperature for a given furnace geometry. Next, the thermal balance calculations downstream the furnace are performed so as the entry and exit temperatures for individual heat exchangers, e.g. platen superheater, convective superheaters, ECO and rotary air heater are estimated and verified against heat transfer equations. The resulting boiler outlet temperature may then be used for calculation of overall boiler efficiency.

When in possession of measurement data, the calculation procedure may be simplified and divided into two major steps. At first, the procedure is based on boiler heat balance which eventually allows for calculation of boiler efficiency. In the case presented here, the efficiency is calculated by the heat loss method as described in standard (DIN1942). At that stage of calculations the mathematical model demonstrates uncertainties equal to those attributed to the measurements [36] while co-firing BFG. In our case the absolute uncertainty of efficiency estimation is therefore $\pm 0.7\%$.

Secondly, the variant calculations are performed in such a way that the minimum number of parameters is modified, e.g. fuel characteristics. The majority of calculation parameters at step no.2 originates either from the original measurements or is kept unchanged from the first calculation step. The uncertainty at step no.2 is only equal to that from step no.1 when the assumption on fouling and slagging invariability may be concluded. For the particular case of boiler co-firing biowaste derived syngas containing only minor fraction of fly ash, it is justified to assume that deposit properties, namely geometric properties and heat transfer conductivity, remain unchanged.

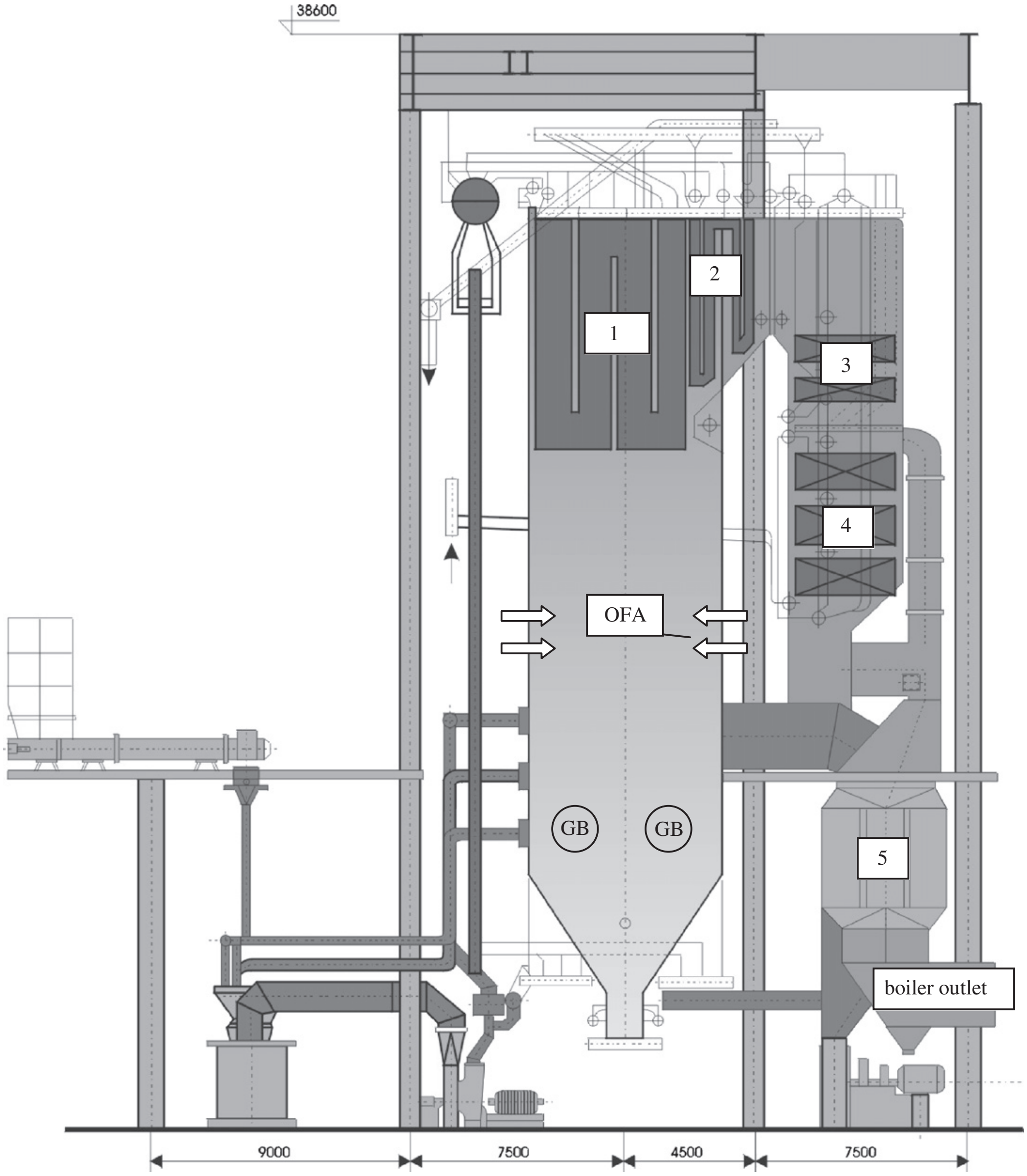

Fig. 2. Schematic of boiler investigated. 1-SH II, 2-SH III, 3-SH I, 4-ECO, 5-RAH, GB-gas burners, OFA-over fire air ports.

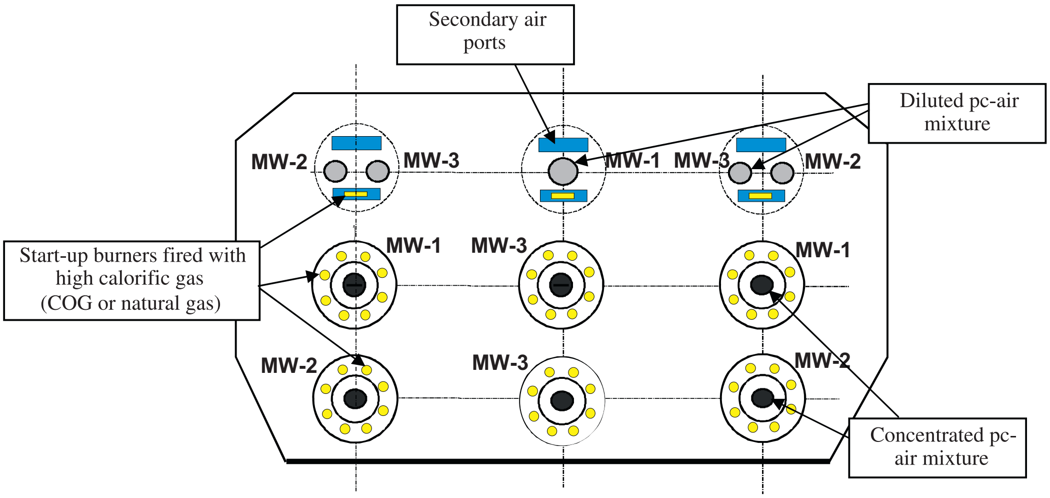
Secondary air ports
Diluted pc-air mixture
MW-2
MW-3
MW-1
MW-3
MW-2
Start-up burners fired with high calorific gas (COG or natural gas)
MW-1
MW-3
MW-1
MW-2
MW-3
MW-2
Concentrated pc-air mixture

Fig. 3. Schematic of the low-emission firing system (view from the inside of the furnace at the front wall).

The chosen LCV gases had similar characteristics to the gases reported in Table 1 and are products from ACFBG and HTAG installations. Both fuel gases are generated from biowaste feedstocks, whose properties are described elsewhere [13,25]. Both gasification technologies were extensively tested [13,25,26,37]. Gas properties were converted into raw (wet) state and are presented in Table 2.

Regarding ACFBG gas, data taken from Table 1 were converted in such a way that they represent the worst operating scenario with respect to the calorific value of the syngas assumed from the raw gas composition. A similar manipulation was made for the HTAG gas. First, the LCV was assumed and then the composition was established so as co-firing of two fuel gases demonstrating possibly extreme operating conditions was studied. The properties of the main fuel – coal, are given in Table 3.

Thermal calculations were performed for a nominal boiler capacity of 230 t/h and for three thermal shares of co-fired LCV gas $X_{\mathrm{ACFBG},\ \mathrm{HTAG}} = 10$, 20 and 40%. Results of thermal calculations are listed in Table 3. In the table the first column refers to the basic case of a boiler firing only coal.

Some results presented in Table 3 need further explanation as they might not be obvious when analyzing the table in the first instance:

Excess air numbers at furnace and boiler outlets: Boiler outlet, according to standards (EN 12952-15 or DIN1942), is located right after rotary air heater therefore far away and downstream furnace outlet. The difference in respective excess air numbers is a result of false air intake between these two cross-sections. The two values are measured in respective boiler locations. In the calculations the furnace excess air factor was kept constant as this is the rule observed in co-firing practice.

Table 2
Properties of gases co-fired in PC boiler, % wet

	ACFBG	HTAG
H_2O	69.66	24.57
CO	2.09	8.98
H_2	2.67	12.90
CH_4	0.00	4.15
C_3H_8	1.55	4.75
CO_2	5.83	7.39
N_2	18.20	37.26
LCV (MJ/m^3_n)	2.0	8.5

Table 3
Results of thermal calculation for boiler OPG 230 co-firing coal and product gas from ACFBG and HTAG installations

	Coal	ACFBG 10%	ACFBG 20%	ACFBG 40%	HTAG 10%	HTAG 20%	HTAG 40%
Boiler capacity (Mg/h)	230	230	230	230	230	230	230
Steam pressure (MPa)	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Drum pressure (MPa)	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Feed water temperature (°C)							
Economizer ECO, inlet	185	185	185	185	185	185	185
Economizer ECO, outlet	300	308	317[a]	317[a]	295	294	294
Spray water flow (Mg/h)	16.09	18.50	24.08	30.42	11.50	12.24	13.30
Coal (as received)							
LHV (MJ/kg)	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Ash content (%)	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Moisture content (%)	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Product gas							
LCV (wet) (MJ/m^3_n)		2.0	2.0	2.0	8.5	8.5	8.5
Steam temperature (°C)							
Superheater SH I, inlet	317	317	317	317	317	317	317
Superheater SH I, outlet	443	455	477	510	432	434	436
Superheater SH II, inlet	413	424	436	444	406	408	409
Superheater SH II, outlet	499	504	514	515	486	487	490
Superheater SH III, inlet	463	458	451	444	467	466	463
Superheater SH III, outlet	540	540	540	540	540	540	540
Flue gas temperature (°C)							
Furnace, outlet	1341	1252	1206	1113	1293	1293	1291
Platen superheater SH II, outlet	1195	1137	1109	1043	1158	1157	1053
Superheater SH III, outlet	1043	997	976	932	1013	1011	1004
Superheater SH I, outlet	639	622	621	623	623	618	610
Economizer ECO, outlet	391	384	386	396	382	378	371
Rotary air heater RAH, outlet	138	157	186	238	159	143	151
Air temperature (°C)							
Rotary air heater RAH, inlet	25	25	25	25	25	25	25
Rotary air heater RAH, outlet	327	337	355	382	325	327	331
Boiler efficiency (%)	90.62	88.75	86.12	80.39	90.58	90.44	90.10
Efficiency drop (%)	0	1.87	4.50	10.23	0.04	0.18	0.52
Fuel consumption:							
Coal (Mg/h)	24.375	22.392	20.511	16.480	21.939	19.531	14.703
Product gas (m^3_n/h)	0	34827	71772	153800	8030	16084	32289
Excess air number:							
Furnace, outlet	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Boiler, outlet	1.57	1.57	1.57	1.57	1.57	1.57	1.57
Air intake (m^3_n/h)	241380	231984	216145	193390	230905	220790	200555
Flue gas flow, boiler outlet (m^3_n/h)	285080	309183	337350	401500	280935	277190	269850
Excess air number increase in pulverizers[b]	0	0	0.05	0.1	0	0	0

[a] Evaporation starts already.

[b] Necessary air intake for compensation of reduced coal consumption and too high air temperature at the inlet to pulverizers.

Air intake vs. flue gas flow: In combustion engineering often the rule of thumb is used which states: the better fuel the more air is needed for its combustion. This rule is derived from basic stoichiometry calculations and does not take into account any other constraints, especially chamber geometry (mixing) limitations. In practice, the combustor operator always balances between certain contradictory parameters: possible lowest excess air, highest fuel burnout, maximum acceptable furnace temperature, lowest emissions, etc. Therefore, firing LCV gas requires less air, if only burnout is achieved, however the total flue gas flow is increased due to amount of LCV gas which must be burnt in order to cover the thermal capacity of replaced coal.

Increase of excess air number in pulverizers: OPG 230 boiler reaches full capacity by operation of two mills out of three. One mill is always kept as a back-up. In the calculation procedure, due to LCV gas contribution, we take into account a load decrease in two mills out of three. Further decrease of the number of working mills is not possible. Boiler would not reach 60% capacity to be covered by coal. Moreover, co-firing of poor 2 MJ/m_n^3 gas requires proper support from coal flame.

The two mills which must work operate under reduced load conditions. In the beater wheel type of mill we consider in the paper, the rule is observed that decreased load is accompanied with increased mill ventilation. Note that for increasing LCV gas share, both flue gas temperature and flue gas flow increase, thus the rotary air heater gives hotter air for mills. Consequently, boiler control system, when it detects too high air temperature at mill inlet, tempers it with fresh air. This extra air contributes to the overall air intake. In the calculations procedure the initial parameters under which mills operate are measured values.

Apart from thermal utilization of biowastes, the main reason behind biomass/biowaste co-firing in boilers concerns CO_2 reduction. Therefore it is reasonable to conduct a more detailed study on the influence of both LCV gases on boiler CO_2 emissions. For the low quality ACFBG gas a significant boiler efficiency reduction, accompanied by unavoidable fuel consumption increase, must be accounted for. In simple terms, neglecting boiler efficiency loss, with a LCV gas thermal share of $X_{ACFBG} = 40\%$, a corresponding 40% coal consumption reduction could be expected compared to coal firing only. For full boiler load this coal consumption reduction equals to 9750 kg/h. Nevertheless, for the conditions presented in Table 3 for ACFBG at 40%, the coal consumption is 16480 kg/h therefore only 7895 kg/h less than in the case of coal combustion only. The difference ($9750-7895 = 1855$ kg/h) is in fact an additional coal consumption due to loss in efficiency, not leading to CO_2 emission reduction. Achieving a desired 40% emission reduction would require a further increase of ACFGB gas thermal share which would result in a further boiler efficiency drop.

For quantitative estimation of expected emission reduction, a relative CO_2 emission decrease factor ΔCO_2 was plotted in relation to the thermal shares of both LCV gases considered in present study, see Fig. 4.

It is clearly visible that in the case of better quality HTAG gas the avoided CO_2 emission is almost equal to the gas thermal share.

Based on the results of the case study presented above, the following areas of concern for boiler operation may be listed:

1. Co-firing of coal with high moisture content ACFBG gas leads to significant changes in boiler operation above certain thermal shares of the gasifier syngas.
2. For increasing thermal share, X_{ACFB}, an increase in steam temperature after each stage of superheating is observed. This may bring about problems with tube lifetime. An increase in spray water flow is also observed.

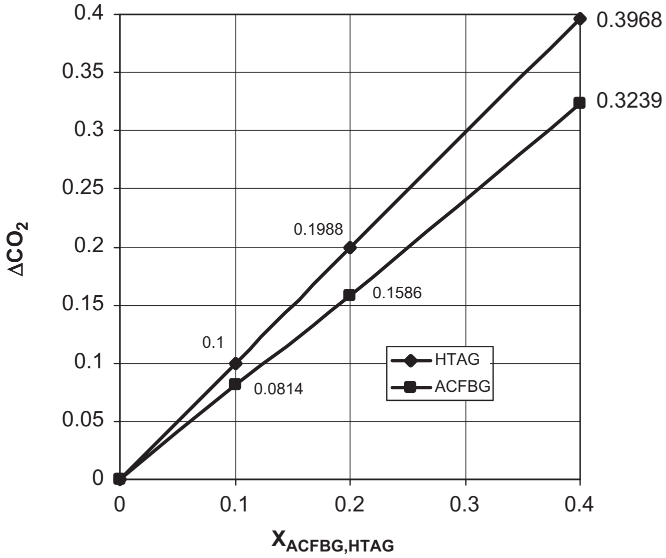

Fig. 4. CO_2 emission reduction in relation to thermal share of LCV gases.

3. Co-firing of ACFBG gas leads to increased flue gas temperatures at the outlet of the boiler. This phenomenon has a direct negative impact on boiler efficiency, and together with increased flue gas flows (approx. 40% by $X_{ACFBG} = 40\%$) affects ESP operation and problems with the ID fan capacity may also occur.
4. Boiler efficiency drop for co-firing of ACFBG gas results in limited coal savings and simultaneously limited CO_2 reductions, not corresponding proportionally to the thermal share of LCV gas.
5. By increasing X_{ACFBG} the temperature of air preheat rises and is additionally accompanied by a reduction of coal being fed to the pulverizers. This implies that the air temperature for the pulverizers could be too high and thus preventive cold air intake must be provided which would further increase the stack loss.
6. Co-firing of larger streams of ACFBG gas leads to partial evaporation of circulating water in the economizer. This in consequence may require rebuilding of the economizer heating surface.

Negative impacts may be contrasted with a list of benefits resulting from co-firing of LCV syngas in power boiler:

1. An increase of thermal input delivered from LCV gas reduces ash volume to be removed from boiler.
2. In contrast to dedicated waste incinerators, co-firing of wastes in power boiler benefits from higher boiler thermal efficiency, as well as the efficiency of the thermal cycle. Moreover, experiences with high temperature corrosion gained by the power industry when implementing low-emission furnaces will certainly help solving problems related to co-firing of chlorine containing wastes.
3. There is no need to shut down the coal boiler when the gasifier is out of operation.
4. Implementing co-firing nozzles or burners requires only minor reconstruction of boiler furnaces. Circulation in the boiler evaporator should not be affected.
5. Coupling a gasifier with a power boiler, while creating an incinerator in legal terms, provides a power generation system which is flexible in terms of feedstocks used.

7. Conclusions

Indirect co-firing of biodegradable wastes derived syngases results in only a minor influence on power boiler operation if a good quality LCV gas is burnt. Thermal input from syngas of at least 20% can be achieved and could even be recommended for proper operation under reburning conditions when injected above the main coal flame. This thermal input is much higher in comparison to direct co-firing percentages which, without special feedstock pre-treatment or dedicated feeding lines, hardly achieve 5%. On the other hand, injection of LCV gas beneath the main coal flame is practiced and results in long residence time and good burnout.

In particular, when analyzing results obtained in present study, it can be clearly stated that co-firing of a modest stream of ACFBG gas accounting for typically 10% of thermal share will not result in operating problems for power boilers and auxiliary boiler devices. Nevertheless, higher thermal shares of ACFBG gas would require major boiler reconstruction.

The negative operational impacts associated with co-firing LCV gas whose calorific value equals to approximately 2 $\mathrm{MJ/m_n^3}$ are not applicable for better quality, 8.5 $\mathrm{MJ/m_n^3}$ gas in which case PC boilers may be easily upgraded for co-firing of large additions, as large as 40%, of biomass/biowaste derived product gas.

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